

**BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2019-226-E**

IN RE: South Carolina Energy Freedom Act)
(House Bill 3659) Proceeding Related to)
S.C. Code Ann. Section 58-37-40)
and Integrated Resource Plans for)
Dominion Energy South Carolina,)
Incorporated)
)
)

**SURREBUTTAL TESTIMONY
OF
KENNETH SERCY
ON BEHALF OF
THE SOUTH CAROLINA SOLAR
BUSINESS ALLIANCE, INC.**

1 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

2 A. My name is Kenneth Sercy. I am an independent electric sector consultant, and my business
3 address is 9042 East 24th Place #102, Denver CO 80238.

4 **Q. ARE YOU THE SAME KENNETH SERCY THAT OFFERED PREFILED DIRECT**
5 **TESTIMONY IN THIS CASE ON JULY 10, 2020?**

6 A. I am.

7 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

8 A. The purpose of this testimony is to respond to the rebuttal testimony of DESC witnesses
9 Bell, Neely, and Lynch, and to comment on several topics covered in ORS witness Sandonato's
10 Exhibit AMS-1 ("The ORS Report").

11 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

12 A. My testimony is organized as follows:

- 13 1. Overview and General Responses to DESC's rebuttal testimony
- 14 2. Responses to DESC's rebuttal statements responding to my direct testimony
- 15 3. Responses to DESC's rebuttal statements on future IRPs
- 16 4. Responses addressing procurement of resources in an IRP
- 17 5. Updated recommendations

18 **OVERVIEW AND GENERAL RESPONSES**

19 **Q. PLEASE PROVIDE A SYNOPSIS OF DESC'S 2020 IRP REVISIONS**
20 **DEVELOPED FOR ITS REBUTTAL TESTIMONY.**

21 A. In response to ORS and intervenor direct testimony, DESC undertook a considerable
22 volume of additional work in order to develop a "supplemental analysis"¹ that is presented in the

¹ DESC Witness Bell rebuttal testimony at 2.

1 Company's rebuttal testimony. In support of its rebuttal testimony, DESC presented over 50%
2 more cost calculations for candidate resource plans than it presented for its original IRP and direct
3 testimony.

4 Producing one cost result broadly entails development of expansion plan spreadsheets,
5 revenue requirements spreadsheets, and a multi-decade production cost model run. DESC
6 produced 144 cost results between July 10 and August 28, compared to 94 cost results produced
7 for the original IRP. And while DESC was able to re-use its original 24 expansion plan
8 spreadsheets, the Company did perform 144 new PROSYM runs, created 80 new revenue
9 requirements spreadsheets, and revised an additional 64 revenue requirements spreadsheets
10 between July 10 and August 28 in order to produce the 144 new cost results.²

11 DESC Witness Bell describes this supplemental analysis as "primarily focusing on the
12 changes recommended in the report issued by J. Kennedy and Associates on behalf of the ORS,"
13 and also describes the analysis as reflecting "in whole or in relevant part, effectively all of the
14 changes that ORS suggested should be made in the 2020 IRP."³ Out of 18 ORS change items listed
15 in Table A of Witness Bell's rebuttal testimony, the Company addressed all but two – revising ICT
16 capital cost assumptions and adding dismantlement costs.⁴

17 In contrast, DESC included just one change item from SCSBA's numerous
18 recommendations – a revised capital cost assumption for battery storage.⁵ In fact, as discussed
19 below, DESC did not refute, or even discuss, the vast majority of critiques and recommendations
20 made in my direct testimony.

² DESC Response to SCSBA Interrogatory 2-2.

³ DESC Witness Bell rebuttal testimony at 2-3.

⁴ Id. at 5-7.

⁵ Id. at 8.

DESC's failure to address SCSBA's recommendations despite the large volume of modeling results it presented on rebuttal suggests two things: first, that DESC has no answer to most of the critiques raised in my direct testimony; and second, that it would not be unduly burdensome to require DESC to perform additional modeling to address the deficiencies raised by SCSBA.

Q. DID DESC'S REBUTTAL TESTIMONY RESPOND TO SCSBA'S 2020 IRP CHANGE RECOMMENDATIONS?

A. DESC responded to some of the SCSBA's recommended changes to the 2020 IRP, but failed to address many others. Here I provide a list of SCSBA's recommendations for the 2020 IRP that DESC did not respond to, and below I review (1) the SCSBA items that the Company did respond to, and (2) additional SCSBA recommendations for future IRPs that the Company did not address.

In summary form, here are the SCSBA recommendations for the 2020 IRP that DESC did not address in its rebuttal testimony. More detailed information is contained in my direct testimony.

1. DESC should revise RP7 into two new candidate resource plans, which include near-term additions of solar and battery storage PPAs, and produce cost results for these plans to compare against revised cost results for the Company's preferred plan, RP2.⁶
2. DESC should correct solar PPA cost assumptions for consistency with actual regional market prices.⁷

⁶ Sercy Direct Testimony at 52-54.

⁷ Sercy Direct Testimony at 16-18.

1 3. DESC should correct the system flexibility requirements for solar PV to comply with
2 previous Commission orders.⁸

3 4. DESC should use the AEO high CO2 case to capture a reasonable range of greenhouse gas
4 policy outcomes.⁹

5 5. DESC should use the new cost results for RP7-A, RP7-B, and RP2 to calculate cost range
6 and minimax regret scores and rankings.¹⁰

7 **Q. BEFORE YOU DISCUSS DESC'S RESPONSES TO OTHER SCSBA**
8 **RECOMMENDATIONS, PLEASE PROVIDE MORE DETAIL ON DESC'S**
9 **SUPPLEMENTAL ANALYSIS AND ITS IMPLICATIONS.**

10 A. DESC modeled the same eight candidate resource plans from the original IRP¹¹, with
11 revisions to the cost calculations based on ORS recommendations. The Company modeled those
12 eight candidate resource plans across the same six scenarios of natural gas and CO2 prices as used
13 in the original IRP.¹² And in addition to modeling the six gas-CO2 scenarios with a Medium DSM
14 assumption, DESC modeled the six gas-CO2 scenarios separately with Low DSM and High DSM
15 assumptions, whereas in the original IRP the Low DSM and High DSM assumptions were only
16 applied to one of the six gas-CO2 scenarios. In short, the Company modeled eight plans across six
17 gas-CO2 scenarios and across three DSM sensitivities, for a total of 144 new cost results
18 produced.¹³

⁸ Sercy Direct Testimony at 44-45.

⁹ Sercy Direct Testimony at 29-30.

¹⁰ Sercy Direct Testimony at 53.

¹¹ DESC Response to ORS Request for Production 9-3.

¹² DESC Witness Bell Exhibit EHB-3 at 1 and 8-9.

¹³ DESC Witness Neely rebuttal testimony at 14.

DESC concluded that the supplemental analysis reinforces the Company's original findings, and affirmed its selection of RP2 as the preferred plan.¹⁴ Ignoring the critiques and recommendations raised in my direct testimony,¹⁵ DESC continues to use unrealistically high assumptions for solar PPA prices, inflated system flexibility requirements for integrating solar PV that the Commission has previously rejected, and unreasonably low natural gas price projections. These unreasonable inputs alone mean that the results of the supplemental analysis are just as unreliable as DESC's original results.

Further, the Company's supplemental analysis did not evaluate resource plans wherein solar PPAs are given a chance to compete with a commercial online date before 2026. And DESC's approach to selecting a preferred plan still does not objectively account for the unprecedented risk and uncertainty present in today's resource planning decisions.¹⁶

Consequently, the supplemental analysis does not cure the deficiencies I described in my direct testimony. DESC's 2020 IRP is still fundamentally flawed, does not align with industry best practices, and fails to comply with Act 62. However, the recommendations I made in my direct testimony can still be readily implemented, and would address the problems with the 2020 IRP to which I've testified. Namely, a relatively small number of additional modeling runs could be performed, in which a few additional key data inputs are updated, in order to produce cost results that would allow for a valid comparison of several candidate resource plans that take different actions in the next three years. Given the large number of additional modeling runs DESC performed in a short period of time for its rebuttal testimony and IRP Supplement, this clearly would not impose an undue burden on DESC.

¹⁴ DESC Witness Bell rebuttal testimony at 33-34.

¹⁵ Sercy Direct Testimony at 52-54.

¹⁶ Sercy Direct Testimony at 5, 23-24, and 33-34.

1 **Q. PLEASE PROVIDE MORE DETAIL ON WHAT DIFFERENT ACTIONS ARE**
2 **AVAILABLE TO DESC IN THE NEXT THREE YEARS.**

3 A. In the eight candidate resource plans that DESC created, no action is taken in any plan prior
4 to 2026. Yet as I discuss in my direct testimony, there are significant actions that could be taken
5 before 2026 and should be evaluated. My recommendations have focused on the option to procure
6 clean energy PPAs with commercial online dates of 2023. If the IRP process fails to even evaluate
7 the economics of such an action, Act 62's direction to fairly evaluate the range of resource options
8 available¹⁷ will not be fulfilled.

9 DESC has now agreed to use a capacity expansion model in future IRPs,¹⁸ which will provide the
10 capability to examine all possible candidate resource plans. While it's probably not practical to
11 utilize this type of modeling for the 2020 IRP, it is possible to achieve part of what a capacity
12 expansion model would do, by simply evaluating additional candidate resource plans under
13 DESC's chosen modeling approach, so that a broader range of potential plans has a fair chance to
14 compete.

15 **Q. DO YOU AGREE THAT DESC'S PREFERRED PLAN IS "FLEXIBLE,"**
16 **ENABLING THE COMPANY TO ADAPT AND SHIFT ITS PATHWAY AS**
17 **ADDITIONAL INFORMATION BECOMES AVAILABLE?**

18 A. Yes and no. While DESC's preferred plan does leave various decisions open for future
19 determination, other candidate resource plans do so as well. And DESC's preferred plan makes an
20 affirmative decision to forego adding (or even planning to add) solar PV for the next several years.
21 While solar PV and battery storage have relatively short construction lead times, bringing these
22 resources online also requires that projects move through the interconnection process, and

¹⁷ Sercy Direct Testimony at 10-11.

¹⁸ DESC Witness Bell rebuttal testimony at 25-26.

1 procurement activities such as RFPs take time as well and typically require regulatory oversight.
2 If such steps are not initiated in the near future, bringing solar PPAs onto DESC's system by 2023,
3 for example, will become infeasible. In other words, adding solar PPAs to DESC's system in the
4 next few years via a proactive approach such as competitive procurement may be difficult to
5 achieve unless it's initiated soon, which is not contemplated in RP2.¹⁹ And as noted above, DESC
6 has not even considered whether adding solar PV in that timeframe is a more reasonable and
7 prudent plan than RP2.

8 From a plan flexibility standpoint, it is also important to recognize that the RP7-A and
9 RP7-B candidate resource plans that I proposed evaluating in my direct testimony are in fact minor
10 variations of RP2 itself. RP7-A, for example, simply shifts the generation source for just 3% of
11 system sales from coal and gas to solar PV; otherwise, it is identical to RP2, and thus also retains
12 substantial plan flexibility.

13 **Q. DO YOU AGREE WITH DESC WITNESS BELL'S STATEMENTS THAT THE**
14 **ACT 62 FACTORS ARE BALANCED BY THE RANGE OF CANDIDATE PLANS DESC**
15 **HAS EXPLORED, AND HIS RELATED COMMENTS ON A THREE-YEAR ACTION**
16 **PLAN?**

17 A. No. Mr. Bell's rebuttal testimony reiterates his direct testimony in claiming that "DESC is
18 presenting all eight resource plans as a range of possible approaches to meeting its customers'
19 future capacity needs,"²⁰ and that "These multiple plans provide the balance that the IRP statute
20 envisions."²¹ But the same could be said of almost any set of resource plans that a utility might
21 include in an IRP. *Any* plan can be adapted over time as new information becomes available;

¹⁹ I would expect a competitive procurement to have to be completed in 2021 in order to successfully bring those projects online by the end of 2023.

²⁰ DESC Witness Bell rebuttal testimony at 32.

²¹ DESC Witness Bell rebuttal testimony at 33.

1 indeed, any plan can and likely will be adapted in this way. It's also meaningless to observe that
2 under different scenarios, candidate plans perform differently. We hardly need detailed modeling
3 and cost calculations to arrive at this understanding – it is a virtually universal conclusion of
4 resource planning analyses. If the bar for balancing the Act 62 factors is simply performing a
5 modeling exercise for multiple candidate plans, then South Carolina ratepayers are not getting
6 much out of the IRP process.

7 The fact that the South Carolina General Assembly included an overhaul of IRP process
8 within Act 62, including a variety of new analytical requirements, a litigated proceeding, and a
9 directive for the Commission to make an explicit determination as to the most reasonable and
10 prudent means of meeting customer demand, strongly suggests that the legislature views the IRP
11 as a key tool for protecting ratepayers and ensuring prudent decision-making in the electric utility
12 industry. The importance recently assigned to the IRP by the General Assembly underscores that
13 utilities aren't meant to simply "check the box" of IRP by performing some modeling runs and
14 concluding that they will change their plans based on what happens in the future.

15 As to the three-year action plan, Mr. Bell states that "An IRP does not authorize the
16 Company to take any action." He points out that the Commission reviews utility applications to
17 acquire new supply resources under the Siting Act, and he asserts that "To treat the IRP as
18 triggering a three- year action plan as to system supply would appear to be a distortion of the IRP's
19 nature and purpose as a planning document not an action plan, and contrary to the regulatory
20 structure in which it operates in South Carolina."²²

21 Yet the Siting Act only applies to proposed resources greater than 75 MW in capacity,²³
22 and under DESC's preferred plan, RP2, the next new supply acquisition occurs in 2035, which

²² DESC Witness Bell rebuttal testimony at 29.

²³ SC Code 58-33-20(2)(a).

1 means a Siting Act proceeding is not likely to occur for DESC for more than ten years. Whether
 2 or not an IRP explicitly authorizes a given action to be taken, a well-crafted IRP provides a
 3 comprehensive comparison of the economics of different resource options for meeting customer
 4 demand under a range of potential future scenarios. If the most reasonable and prudent plan
 5 identified through the IRP process were to include, for example, solar PPAs coming online well
 6 before the next Siting Act proceeding would occur, there should be an expectation that the utility
 7 will take the actions needed to acquire those resources.²⁴ A short-term action plan is an appropriate
 8 element to include in an IRP document to clearly identify such actions that are expected to be
 9 taken, whether or not those actions require additional regulatory proceedings in order to be fully
 10 carried out.

11 DESC recognizes that practically speaking, it would be impossible to not select an
 12 individual plan, as evidenced by statements such as “The base plan presented, RP2, is the plan the
 13 Company will use as a reference plan until conditions indicate otherwise,” and “DESC...will rely
 14 on Resource Plan 2 for avoided cost determinations until a new plan is prepared.”²⁵ Indeed, my
 15 direct testimony notes that utility IRPs play a role in a variety of regulatory matters, such as setting
 16 avoided cost rates and as inputs within value of solar calculations and DSM cost-effectiveness
 17 tests.²⁶ Balancing the seven factors listed in Act 62 is necessary to select the most reasonable and
 18 prudent plan – the balancing isn’t accomplished simply by the act of performing modeling runs.
 19 Further, a short-term action plan memorializes the actions that will be taken in the near term
 20 according to the selected plan.

²⁴ Act 62 authorized the PSC to “open a generic docket for the purposes of creating programs for the competitive procurement of energy and capacity from renewable energy facilities by an electrical utility within the utility’s balancing authority area if the commission determines such action to be in the public interest.” SC Code 58-41-20(E)(2).

²⁵ DESC Witness Bell rebuttal testimony at 32-33.

²⁶ Sercy direct testimony at 5.

1 **Q. DO YOU AGREE THAT ACT 62 ESTABLISHED A “LEAST COST RESOURCE**
 2 **PLAN STANDARD” AS STATED ON PAGE 1 THE ORS REPORT²⁷?**

3 A. No. As I describe in my direct testimony, Act 62 clearly established a “reasonable and
 4 prudent” standard. “Least cost” is just one of seven factors the Commission is directed to consider.
 5 Additionally, two of those factors²⁸ relate to the concepts of risk and uncertainty, which aligns
 6 with Act 62’s requirement to perform scenario analysis. Far from establishing a least cost standard
 7 that seeks a plan that performs best under a current outlook scenario, Act 62 sets a standard that
 8 chooses a plan considering multiple future scenarios and forecasted costs plus risks and other
 9 factors.

10 **RESPONSES TO DESC’S RESPONSES**

11 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY CONCERNING THE**
 12 **UNREASONABLENESS OF DESC’S SOLAR PPA COST ASSUMPTIONS.**

13 A. In my direct testimony, I described how DESC’s solar PPA pricing model produces results
 14 that are inconsistent with actual market prices in the Carolinas²⁹, and I recommended using the
 15 NREL ATB Low Case input assumptions in place of the ATB Mid Case assumptions that the
 16 Company uses. DESC’s PPA pricing model calculates a price of \$47.77 / MWh for 2019 projects,
 17 compared to 2019 CPRE average winning bid prices of \$38 / MWh. Using the Low Case
 18 assumptions, the pricing model calculates a 2019 price of \$42.15 / MWh, which is an initial price
 19 point that is closer to actual regional prices (though, notably, still conservative).

²⁷ ORS Witness Sandonato direct testimony, Exhibit AMS-1.

²⁸ “Commodity price risk” and “diversity of generation supply” S.C. Code Ann. 58-37-40(C)(2).

²⁹ SCSBA Witness Sercy direct testimony at 16-17.

1 The inaccurately high starting point used by DESC results in unrealistic prices for the entire
2 2020-2050 projection. Calibrating the PPA pricing model, so that its results are consistent with
3 actual market prices, is essential to ensuring that the results for future years are realistic.

4 My direct testimony also addressed federal Investment Tax Credit (“ITC”) assumptions,
5 explaining that the PPA pricing model should correctly incorporate the safe harbor provisions
6 highlighted in the CRA Report, which I discuss further below.

7 **Q. DID DESC’S REBUTTAL TESTIMONY RESPOND TO YOUR TESTIMONY ON**
8 **THE ASSUMPTIONS USED IN THE PPA PRICING MODEL?**

9 A. Only in part. Mr. Neely’s rebuttal testimony responds to my testimony on how the federal
10 ITC is represented in the PPA pricing model. However, DESC did not respond to my
11 recommendation to use the NREL ATB Low Case assumptions, or to my assertion that solar PPA
12 assumptions within IRP modeling should reflect current data on actual regional market prices.

13 **Q. PLEASE RESPOND TO MR. NEELY’S REBUTTAL TESTIMONY ON THE**
14 **FEDERAL ITC.**

15 A. Mr. Neely notes that even when my recommendation to incorporate the safe harbor
16 provision into the PPA pricing model is implemented, the federal ITC declines to 10% by 2026,³⁰
17 which is when the solar PPAs come online in RP7 and also when owned solar and battery storage
18 assets come online in various candidate resource plans. While that point is correct, it ignores two
19 important issues. First, as I described above, the Company hasn’t calibrated its model for
20 consistency with actual market prices, which results in an unrealistic PPA price result for 2026
21 that is independent of federal ITC treatment. Second, one of my primary recommendations for
22 bringing DESC’s 2020 IRP into compliance with Act 62 is for the Company to model a revised

³⁰ DESC Witness Neely rebuttal testimony at 18.

1 RP7 wherein the solar PPAs come online in 2023 rather than 2026. In 2023, the safe harbor
2 provisions for the ITC still allow projects to access at least the 22% credit, and it's important to
3 capture this in a revised RP7 cost calculation. Conversely, by delaying solar PPAs until 2026,
4 after the ITC step-down, DESC unreasonably inflates solar PPA pricing even further than it already
5 had by not calibrating its pricing inputs to regional market data (which may explain why the
6 Company made the choice to add PPAs in 2026).

7 **Q. COULD YOU ALSO RESPOND TO THE COMPANY'S REBUTTAL**
8 **TESTIMONY ON RENEWABLE ENERGY DE-ESCALATION?**

9 A. Mr. Neely's rebuttal testimony describes a correction to the projected capital cost figures
10 for solar PV and battery storage, which was prompted by an ORS recommendation.³¹ While I agree
11 with this correction, it must be applied to an appropriate set of input assumptions – that is, for solar
12 PV, the NREL ATB Low Case rather than the Mid Case, consistent with my above statements on
13 appropriately calibrating the pricing model to reflect real-world market data.

14 I have applied Mr. Neely's correction to the solar PV Low Case PPA pricing model, also
15 using appropriate ITC safe harbor assumptions as described in my direct testimony. I made one
16 additional adjustment to the model, to reflect geographic differences in solar PV installed costs,
17 whereby Southeastern regional installed costs are about 10% lower than the national median.³²
18 This updated PPA pricing model calculates a 2023 PPA price of 38.94 \$ / MWh. A 20-year PPA
19 initiated in 2023 would expire in 2043 and would need to be replaced with a new 20-year PPA.
20 The pricing model calculates a 2043 PPA price of 34.93 \$ / MWh. These are reasonable PPA price
21 assumptions for use in a revised RP7 wherein solar PPAs are added in 2023 and 2043.

³¹ DESC Witness Neely rebuttal testimony at 7-8.

³² M. Bolinger et al. Utility Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the US - 2019 Edition. Lawrence Berkeley National Laboratory (December 2019) at 23.

1 **Q. HOW DOES A GENERIC ASSUMPTION OF 38.94 \$ / MWH FOR A 20-YEAR**
2 **SOLAR PPA, INITIATED IN 2023, RELATE TO THE REALITY OF SOLAR PV**
3 **MARKET IN DESC'S SERVICE TERRITORY?**

4 A. It is important to recognize that utility-scale solar PV projects are not homogeneous; rather,
5 projects vary by size, siting characteristics, interconnection costs, equipment and design choices,
6 and other factors. Thus, in reality, a supply curve exists whereby so many megawatts of solar PV
7 capacity could be developed for a given price, an additional amount of capacity could be developed
8 for a higher price, and so on. So while a 2023 price of 38.94 \$ / MWh is a reasonable generic
9 assumption to use in the 2020 IRP modeling, additional sensitivities would be quite valuable to
10 run, as I will discuss further below.

11 **Q. GIVEN THE LARGE PRICE REDUCTIONS IN SOLAR PV OVER THE PAST**
12 **DECADE, IS IT REALISTIC TO EXPECT FURTHER PRICE REDUCTIONS GOING**
13 **FORWARD?**

14 A. Yes. First, the recently released 2020 version of the ATB projects significantly lower solar
15 PV costs than the 2019 version.³³ For example, the 2019 Low case, which is the basis of the solar
16 PPA prices I have recommended using for DESC's 2020 IRP, generally falls between the 2020
17 Mid case and the 2020 Low Case, including for the out years of the projections. This illustrates
18 that the inputs I recommend using not only reasonably reflect recent market prices, but also result
19 in a more moderate long-term projection than the corresponding case from the most recent ATB
20 version. Second, the NREL ATB documentation highlights a wide array of cost reduction
21 opportunities cited in industry and academic literature that may be realized as the industry

³³ NREL (National Renewable Energy Laboratory). 2020. "2020 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. <https://atb.nrel.gov/>.

1 continues to grow. Exhibit 1 provides a summary of cost reduction potential related to solar PV
2 modules, balance-of-system components, power electronics, and installation and margins.

3 It is reasonable to expect solar PPA prices to decline to 34.93 \$ / MWh in 2043, a small
4 reduction of approximately 10% from today's prices. The updated PPA pricing model projects that
5 prices modestly decline for the next 10 years and then level off, which is consistent with the ORS
6 Report statement that "While commodity prices and technological advances may continue to
7 reduce the price of solar and battery technologies, it would be more appropriate for DESC to only
8 apply the de-escalation of overnight capital costs for a shorter fixed period of time rather than for
9 the entire study period."³⁴

10 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING BATTERY**
11 **STORAGE COST AND PERFORMANCE ASSUMPTIONS.**

12 A. My direct testimony on battery storage focuses on reasonable assumptions for battery PPA
13 costs, because battery PPAs are another component of my recommendation to model two revised
14 versions of RP7. I recommended that "RP7-B," one of the candidate plans I proposed should be
15 modeled by DESC, should use the NREL ATB's medium storage cost case and 22% ITC safe
16 harbor assumptions that would apply to a solar plus storage PPA, because these input assumptions
17 are more consistent with regional market prices as indicated in Santee Cooper's recent RFI.³⁵

18 **Q. WHAT IS YOUR RESPONSE TO DESC'S TESTIMONY ON THIS ISSUE?**

19 A. Mr. Neely has agreed that the NREL ATB mid case battery storage cost assumptions are
20 the most reasonable inputs for this technology, with a modification to correctly use nominal dollar
21 values. While this change to DESC's assumptions is an improvement, the nominal dollar
22 correction pushes the battery PPA model results substantially higher than the prices indicated in

³⁴ ORS Report at 58.

³⁵ Sercy direct testimony at 18-19.

1 the Santee Cooper RFI. For the purpose of modeling battery PPA prices for RP7-B, I would like
 2 to update my recommendation to use the ATB low case battery cost assumptions, which including
 3 the nominal dollar correction are actually more consistent with the Santee Cooper RFI results than
 4 the mid case assumptions originally were. I have updated the battery PPA pricing model with these
 5 inputs, which yields a 2023 battery PPA price of 129.79 \$ / kW-year and a 2038 price of 95.28 \$
 6 / kW-year. Similar to the updated solar PPA pricing model, this updated battery PPA pricing model
 7 projects continued technology cost declines for the next 10 years, after which costs level off,
 8 consistent with the ORS Report de-escalation recommendation noted above.³⁶ To be clear, none
 9 of DESC's eight candidate plans includes battery PPAs, which underscores the importance of
 10 evaluating this resource option within RP7-B.

11 Additionally, in response to an ORS recommendation, DESC has assumed a 30-year
 12 project life for owned battery storage, in conjunction with adding O&M costs that include life
 13 extension.³⁷ DESC's original modeling of battery storage PPAs used the NREL ATB assumption
 14 of a 15-year project life, with 2% annual degradation.³⁸ However, the ATB documentation
 15 specifies that NREL has "adopted a fixed operations and maintenance (FOM) value from the high
 16 end and assume that the FOM cost will counteract degradation such that the system will be able to
 17 perform at rated capacity throughout its lifetime," assuming one charge-discharge cycle per day.³⁹
 18 DESC described the typical performance of the battery storage in its candidate resource plans as
 19 averaging "1 charge and 1 discharge per day".⁴⁰ Therefore, a reasonable approach to modeling
 20 battery storage PPAs would be to assume a 15-year life, NREL ATB low case nominal capital and

³⁶ ORS Report at 58.

³⁷ DESC Witness Neely rebuttal testimony at 17.

³⁸ DESC Response to SCSBA Interrogatory 1-18

³⁹ Cole, Wesley, and A. Will Frazier. 2020. Cost Projections for Utility-Scale Battery Storage: 2020 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-75385.

⁴⁰ DESC Response to SCSBA Interrogatory 1-18.

O&M costs, no degradation, and after the initial PPA expires, a new 15-year PPA would be added at the capital, O&M, and financing costs for that future year. I recommend using this approach for purposes of modeling the battery storage PPA included in the RP7-B plan I describe within my 2020 IRP change recommendations.

Collectively, these battery storage assumptions ensure that representation of storage PPAs in RP7-B correctly meets reserve margin targets throughout the modeling period, and does so using appropriate technology cost and PPA replacement assumptions.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING SOLAR CAPACITY VALUE.

A. I noted that the PSC has recently rejected DESC's assumption that incremental solar PV has zero winter capacity value, and that the Commission instead adopted an 11.8% ELCC value to appropriately recognize the capacity value solar provides. I recommended that the 2020 IRP modeling should capture this capacity value, updated to reflect any relevant changes in the amount of solar PV on the system.⁴¹

Q. HOW DO YOU RESPOND TO DESC WITNESS LYNCH'S REBUTTAL TESTIMONY ON THIS ISSUE?

A. Dr. Lynch asserts that the Commission "did not order the Company to assume 11.8% of nameplate solar capacity would be available to serve the winter peak demand, which occurs before sunrise...."⁴² While the Commission did not adopt an assumption that solar PV would provide a high level of capacity value during early morning winter peaks, it recognized that capacity need exists across all hours of the year, such that a resource can have capacity value even if it does not contribute capacity in the absolute highest peak hour. A utility's capacity need is a function of both

⁴¹ Sercy direct testimony at 18.

⁴² DESC Witness Lynch rebuttal testimony at 24.

1 load and forced outages at generation and transmission assets. Load is present at all hours of the
 2 year, as is the chance of forced outages. This includes all winter season daytime hours, not just
 3 winter morning hours. This is why the Commission concluded in its Avoided Cost Order that
 4 “ORS witness Horii’s recommended 11.8% avoided capacity value is appropriate as it is reflective
 5 of the actual avoided capacity value for solar at this time,”⁴³ highlighting that “Mr. Horii testified
 6 that, in addition to incorrectly asserting that solar provides no capacity value in the winter, DESC
 7 understated the avoided capacity costs due to several incorrect assumptions....”⁴⁴ The ELCC
 8 methodology adopted by the Commission appropriately recognizes both the contribution of solar
 9 generation during early winter mornings (however minor it may be), and the larger contribution of
 10 solar during other winter daytime hours, when load and forced outages can create significant
 11 capacity needs.

12 Dr. Lynch’s rebuttal statements also seem to suggest that these concepts do not apply
 13 outside of an avoided cost context. In fact, ELCC values are used widely in electric sector
 14 modeling, including in long-term resource planning. In an avoided cost context, ELCC values are
 15 part of the calculations that identify the rates that should be paid to QF projects; in a resource
 16 planning context, ELCC values are used to identify the capacity contribution of resources such as
 17 solar PV so that candidate resource plans that contain those resources are correctly designed to
 18 meet reliability targets. The Commission’s findings in Order 2020-244 that solar PV has winter
 19 capacity value, and that the overall solar capacity value at that time was accurately reflected in an
 20 11.8% ELCC, apply equally in the current resource planning context.

21 A reasonable approach to applying these findings in the 2020 IRP is to use summer and
 22 winter contributions of 11.8% (or an appropriate updated ELCC value based on current penetration

⁴³ SCPSC Order 2020-244 at 11.

⁴⁴ SCPSC Order 2020-244 at 10.

1 level), for purposes of creating the expansion plans for candidate resource plans containing
2 incremental solar PV, such as RP7. And while this approach could also be applied to existing and
3 under contract solar PV on the DESC system, including varying the ELCCs as appropriate for each
4 penetration level, this wouldn't substantially change the overall analytical results, since it would
5 be applied equally to all candidate resource plans. In contrast, updating the modeling to account
6 for the winter capacity value of incremental solar PV, such as the solar PV added in RP7, does
7 impact the overall results by appropriately recognizing capacity value that is not included in
8 DESC's cost results thus far.

9 Finally, further refinement in the future of ELCC methodologies and how to apply them to
10 IRP would be worthwhile.

11 **Q. HOW DO YOU RESPOND TO DESC WITNESS LYNCH'S REBUTTAL OF YOUR**
12 **TESTIMONY ON THE RESERVE MARGIN TARGET OF CANDIDATE RESOURCE**
13 **PLANS?**

14 A. Dr. Lynch briefly describes the Company's IRP process, and concludes by stating that "To
15 plan the system to require a 21% reserve margin to be supplied by base capacity resources would
16 risk burdening customers with unnecessary costs."⁴⁵

17 DESC's process entails creating candidate resource plans that meet its base reserve margin,
18 and subsequently adding resources to each plan so that its additional peaking reserve margin is
19 also met. In the second step, the resource options are highly limited to include only short-term
20 purchases, demand response, and upgrades to existing peaking resources. In other words, in
21 evaluating how to meet its additional peaking reserve margin, the Company doesn't allow the vast

⁴⁵ DESC Witness Lynch rebuttal testimony at 23-24.

1 majority of potential resource options to compete, and thus is excluding hundreds of megawatts
2 from the basic IRP objective of comparing options for meeting customer needs.

3 My direct testimony did not suggest that a 21% reserve margin target has to be met by
4 "base capacity resources." Rather, I recommended that the full peaking reserve margin target
5 should be used in the process whereby candidate resource plans are fairly evaluated against one
6 another for meeting customer needs. This same point is made by DESC's consultant Charles River
7 Associates ("CRA")⁴⁶ and in the ORS Report, which states that "In the future, the Company should
8 employ an economic decision making process in deciding whether to add short term capacity
9 purchases or some other type of resource in its IRP."⁴⁷ If short-term purchases are indeed the most
10 economic way of meeting the peaking reserve need, a fully inclusive comparison, as I have
11 recommended, will show that to be true. However, if some other way of meeting the peaking
12 resource need is actually more cost-effective, Dr. Lynch's approach could overlook that other
13 resource since it only considers a few possibilities. In reality, it is Dr. Lynch's recommendation
14 that risks burdening customers with unnecessary costs.

15 The IRP process should not pre-judge outcomes by assuming, prior to doing the analysis,
16 that certain resources are more or less economic. Rather, the analysis should be inclusive (all
17 resources should be able to compete to meet all needs), and the results will speak for themselves.
18 DESC's analysis did not evaluate candidate resource plans where the peaking reserve is met by
19 resources other than short-term capacity purchases; thus, the analysis cannot tell us which
20 resources meet these needs most cost-effectively.

21 It's also worth noting that use of a capacity expansion model could substantially ease the
22 adoption of my recommendation on this point. If all resource options are made available to the

⁴⁶ As cited in SCSBA Witness Sercy direct testimony at 21.

⁴⁷ ORS Report at 60.

1 model, and the model's reserve margin target is the full peaking reserve, then the software will
2 compare all possible resource plans and identify the lowest cost plan for meeting the reserve
3 margin target.

4 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING THE**
5 **INCLUSION OF POWER PURCHASES AS A RESOURCE OPTION.**

6 A. My direct testimony pointed out that off-system power imports "are an available means of
7 meeting capacity and energy needs and could play a role in a reasonable and prudent resource
8 plan." I recommended that power purchases should be included as resource options in future IRPs,
9 and evaluated within candidate resource plans across multiple scenarios.⁴⁸

10 **Q. HOW DO YOU RESPOND TO DESC WITNESS NEELY'S REBUTTAL**
11 **TESTIMONY ON THIS ISSUE?**

12 A. Mr. Neely provides three reasons for excluding off-system power purchases as a resource
13 option that could be included in candidate resource plans. He states that such purchases create "a
14 system reliability risk," are surveyed for price competitiveness via RFP as part of Siting Act
15 procedures, and have uncertain future cost and availability profiles that create modeling
16 challenges.⁴⁹

17 However, a large portion of the US electricity sector is made up of utilities whose power
18 supply comes entirely or mostly from long-term power purchases. This includes electric
19 cooperatives and municipal utilities all over the country. With industry-standard contract
20 provisions in place, power purchases are a demonstrably reliable supply source. As to Siting Act
21 RFPs, as I noted in a previous response, in DESC's preferred plan, the next Siting Act application
22 won't be submitted for more than a decade. Finally, DESC's 2020 IRP already makes cost and

⁴⁸ Sercy direct testimony at 20 and 22.

⁴⁹ DESC Witness Neely rebuttal testimony at 13.

1 availability assumptions for power purchases, including those modeled many years into the
2 future.⁵⁰ Reasonable assumptions can be identified for long-term purchases just as they can be
3 identified for short-term purchases. The ORS Report comments that "...it is not inappropriate for
4 a utility to include capacity purchases in its IRP or to actually make capacity purchases...."⁵¹

5 Notably, this point also overlaps with my previous response to Dr. Lynch on the peaking
6 reserve margin. That is, both short- and long-term purchases could be part of a prudent resource
7 plan, and they should be evaluated within candidate resource plans that are designed to meet
8 DESC's full peaking reserve margin. A comprehensive economic analysis will determine the most
9 reasonable and prudent means of meeting demand. There is no need to divide the reserve margin
10 into separate components or arbitrarily define certain resources as "base resources" and others as
11 "peaking resources," which amounts to pre-judging the outcomes of the analysis.

12 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING DESC'S**
13 **NATURAL GAS PRICE PROJECTIONS.**

14 A. My direct testimony discusses how DESC's natural gas price projection methodology is
15 unreasonable and produces base, low, and high price forecasts that are all unreasonably low. I
16 discuss how the US DOE's model NEMS, which is used to produce the Annual Energy Outlook
17 (AEO), simulates gas supply and demand in detail. This is an appropriate approach to forecasting
18 wide-ranging but plausible gas price trajectories.⁵²

19 **Q. HOW DO YOU RESPOND TO DESC WITNESS NEELY'S REBUTTAL**
20 **TESTIMONY ON THIS ISSUE?**

⁵⁰ DESC's power purchase cost assumptions are discussed in the ORS Report at 59-60.

⁵¹ ORS Report at 60.

⁵² Sercy direct testimony at 26-29.

1 A. Mr. Neely notes that the Energy Information Administration's AEO 2020 is now available,
2 and states that its reference case includes natural gas price projections that are closer to DESC's
3 base case projections than are the AEO 2019 reference case projections. Mr. Neely doesn't offer
4 any additional support for his conclusion that DESC's projections are "not unreasonable."⁵³ Thus,
5 he does not respond to my assertion that it is essential to model gas supply and demand in order to
6 identify reasonable gas price projections, which DESC did not do. I support using the most up-to-
7 date AEO projections for modeling purposes, and in fact, the AEO prices I refer to, display, and
8 recommend in my direct testimony are the AEO 2020 prices. To reiterate from my direct
9 testimony, "On average, the AEO prices are 19% higher than DESC's in the base case, 14% higher
10 in the high case, and 23% higher in the low case. These price differences have very large impacts
11 on production costs and overall candidate resource plan cost results across the scenarios, with
12 lower gas price assumptions favoring gas-fired resources."⁵⁴

13 To be clear: calculating year-by-year escalation rates from AEO price projections and then
14 applying those rates to an initial NYMEX price, as DESC does, is not an appropriate methodology
15 for forecasting long-term prices. Such an approach has the result that transient short-term market
16 dynamics, such as gas storage inventories and recent weather patterns, become reflected in long-
17 term prices. As discussed in my direct testimony, the AEO represents complex long-term market
18 interactions to project prices, and the resulting time series of gas prices is what should be used
19 directly as gas price inputs. Changing long-term market dynamics are captured as various data and
20 structural shifts are incorporated into the AEO as part of its annual release schedule. My direct
21 testimony supports using an initial year of NYMEX prices in recognition of the time lag between
22 AEO releases. However, the appropriate manner in which to use that NYMEX data point, without

⁵³ DESC Witness Neely rebuttal testimony at 29-30.

⁵⁴ SCSBA Witness Sercy direct testimony at 28.

1 inappropriately carrying short-term market impacts through the entire multi-decade price forecast,
 2 is to transition in the near term from a pure NYMEX year one price to a pure AEO price. For
 3 example, the year two price could be the midpoint between the NYMEX and AEO prices, with
 4 year three and all future years then directly using the AEO prices.

5 Finally, I'd like to note how NYMEX prices have changed since December 2019, when
 6 DESC obtained NYMEX pricing data⁵⁵ for use in its long-term gas price forecasts. At that time,
 7 NYMEX prices for 2021 were \$2.42 / mmbtu.⁵⁶ As of September 2020, NYMEX prices for 2021
 8 are now around \$3 / mmbtu (above \$3 early in the year, and slightly below \$3 for the remainder
 9 of the year).⁵⁷ The latest Short-Term Energy Outlook report from the Energy Information
 10 Administration projects that the monthly average Henry Hub gas price will be \$3.19 / mmbtu for
 11 2021.⁵⁸ For reference, that 2021 price point is higher than the 2021 price in all three of the AEO
 12 2020 gas forecasts that I propose using (the AEO High case includes a 2021 price of \$2.97 /
 13 mmbtu).

14 **Q. WHAT DID ORS CONCLUDE AND RECOMMEND ON NATURAL GAS PRICE**
 15 **PROJECTIONS, AND HOW DO YOU RESPOND?**

16 A. The ORS Report compared “the Company’s low, base and high gas price forecasts to other
 17 recent utility and industry forecasts that are publicly available” and also created low, base, and
 18 high “consensus forecasts” by averaging the values of the public forecasts for each year.⁵⁹ That
 19 comparison showed that the “DESC gas price forecasts are lower than the comparative forecasts,
 20 including the consensus forecast in all three (3) gas price cases.”⁶⁰ The ORS Report also discusses

⁵⁵ ORS Witness Sandonato direct testimony, Exhibit AMS-1 at 45.

⁵⁶ DESC Response to ORS Request for Production 9-2.

⁵⁷ US Energy Information Administration. Short-Term Energy Outlook, September 2020 at 16.

⁵⁸ US Energy Information Administration. Short-Term Energy Outlook, September 2020 at 2.

⁵⁹ ORS Report at 46.

⁶⁰ ORS Report at 48.

1 concerns with DESC's gas forecast methodology, including the following: "ORS is concerned that
2 the Company's escalation methodology may understate gas prices beyond the initial three year
3 forecast in the low and base gas price sensitivities".⁶¹ The ORS conclusions that the DESC gas
4 forecasts are unreasonably low and that the Company's escalation methodology leads to flawed
5 long-term price points are both consistent with my conclusions above. Yet the Report does not
6 recommend a particular methodology and also does not recommend that the 2020 IRP modeling
7 utilize different gas projections than those used by DESC thus far – instead, the Report's overall
8 recommendation is that DESC should revisit these points for future IRPs.

9 I agree with ORS's conclusions on gas prices but disagree with the ORS Report's overall
10 recommendation to revisit these points in the future as opposed to now, because a reasonable
11 methodology and set of forecasts is available and can be incorporated into revised modeling runs
12 for the 2020 IRP. My direct testimony recommendation to rely on a widely respected public model
13 that simulates natural gas supply and demand is a reasonable methodology for deriving natural gas
14 price forecasts, whereas DESC's methodology is not. Notably, the ORS Report comparison graphs
15 show that the AEO forecasts generally fall between the DESC forecasts and the "consensus
16 forecast," which illustrates that on average the prices assumed in the public sources surveyed by
17 Kennedy & Associates are higher than those simulated in the AEO. Thus, the AEO projections
18 represent a reasonable approach and also appear to be conservative relative to numerous public
19 gas forecasts.

20 Natural gas price assumptions are key data inputs within the IRP modeling, exerting a very
21 powerful influence on system operations and total revenue requirements for each plan. And they
22 can be readily altered for the purpose of revised production cost model runs. My direct testimony

⁶¹ ORS Report at 48.

1 recommendations recognize that certain appropriate changes cannot be readily implemented
2 within the 2020 IRP – such as adopting a capacity expansion model. But natural gas price
3 assumptions are not one of those types of changes. They can and should be corrected to use
4 reasonable values in the 2020 IRP. DESC could have incorporated this change into its 144
5 additional cost results produced for its supplemental analysis. Even now, a relatively small number
6 of further cost results could easily be produced that use reasonable gas price forecasts.

7 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY ON RISK METRICS.**

8 A. DESC did not utilize a risk assessment in selecting its preferred resource plan, and thus did
9 not adequately consider the Act 62 factors for identifying a reasonable and prudent plan. Cost
10 ranges and max regret scores are two simple risk metrics that can be calculated from traditional
11 scenario analysis results such as those produced by DESC in the 2020 IRP. These risk metrics
12 provide a systematic and objective methodology for quantifying the risk associated with each
13 candidate resource plan. Comparing risk metric values for the candidate plans is an appropriate
14 means for considering Act 62 factors such as commodity price risk and diversity of generation
15 supply.⁶²

16 **Q. DID DESC RESPOND TO YOUR TESTIMONY ON THIS ISSUE?**

17 A. The Company did not directly respond to my testimony on risk metrics. DESC did add a
18 new metric within its supplemental analysis: average ranking. DESC provides average rankings
19 for each of its eight candidate resource plans by first ranking the plans from least cost to highest
20 cost within each scenario, and second, averaging the resulting rankings for each plan across all
21 scenarios. However, this is not an appropriate approach to measuring risk and uncertainty.
22 Averages, considered by themselves, have the effect of hiding risk. For example, one or two

⁶² Sercy direct testimony at 36-37.

1 important high cost results for a given candidate resource plan could be masked within an overall
2 average. This would expose customers to the risk of bearing high costs in those particular
3 scenarios, even if the plan overall had a low average ranking. To illustrate, DESC found RP2 to
4 have the lowest average ranking⁶³, a value of 2.17, but that low average ranking wouldn't matter
5 for ratepayers under the base gas, \$25 CO2 scenario where RP2 is ranked fifth out of the eight
6 plans.⁶⁴ The purpose of risk analysis is to identify and quantify such risks, not to hide them. This
7 is why risk metrics typically include variance or standard deviation, which indicate cost ranges,
8 and high percentile values, which are similar to the max regret, rather than averages alone.⁶⁵

9 It's also important to keep in mind that while rankings generally can be useful for
10 understanding how plans performed relative to one another, the difference between one rank and
11 the next can technically be \$1 or \$10 million or any other amount, and those difference amounts
12 inevitably vary from rank to rank. Those differences become quite obscured when rankings are
13 averaged together.

14 **Q. DID YOU CALCULATE COST RANGE AND MAX REGRET SCORES FOR**
15 **DESC'S REVISED RESULTS?**

16 A. Yes. Exhibit 2 compiles DESC's new cost results and provides rankings by scenario and
17 also for the cost range and max regret risk metrics.

18 First, note that Exhibit 2, Tables 1 and 2 present DESC's cost results appropriately in terms
19 of 24 candidate resource plans across six gas-CO2 scenarios. As I discuss in my direct testimony,
20 DSM is a resource option, not a factor akin to natural gas prices that DESC has no control over.
21 DSM is deployed at a level of the Company's choosing, subject to PSC oversight, just like any

⁶³ DESC Witness Bell rebuttal testimony, Exhibit EHB-3 at 13.

⁶⁴ DESC Witness Bell rebuttal testimony, Exhibit EHB-3 at 10.

⁶⁵ As illustrated by example utilities and risk metrics discussed in Sercy direct testimony at 34.

1 supply-side resource. Thus, in Exhibit 2, I present the candidate plans that include Medium DSM
 2 as RP1 through RP8, and I present the candidate plans that include High and Low DSM as RP1-H
 3 through RP8-H and RP1-L through RP8-L, respectively.

4 Exhibit 2 Table 2 shows that, similar to DESC's original cost results, no one plan is least
 5 cost across all six scenarios, and any given plan that does well in one scenario does not necessarily
 6 perform well in others. In other words, the same conclusion I drew from the original results applies
 7 equally here: the cost results don't provide an obvious best choice from a least-cost standpoint.

8 Exhibit 2 Tables 3 and 4 provide the cost range and max regret values and rankings. RP2,
 9 which includes Medium DSM, ranks 19th out of 24 for cost range, and 7th out of 24 for max regret.
 10 Thus, it performs poorly on the cost range metric, with one of the widest ranges of the candidate
 11 plans, while performing better but not at the top of the max regret rankings. By comparison, RP7,
 12 which includes Medium DSM and solar PPAs, again outperforms RP2 on both risk metrics, just
 13 as it did in the original results. RP7 ranks 12th of 24 on cost range and 5th of 24 on max regret.
 14 These results further illustrate that the average ranking metric that DESC has introduced into its
 15 revised results does not capture risk exposure well, and in fact actually hides risk.

16 I discuss the implications of these revised results for DSM further below. And finally, I
 17 would like to reiterate that I use DESC's results here only to illustrate and compare risk metrics
 18 such as cost range, max regret, and the Company's "average ranking," which could be interpreted
 19 as an attempt to include a risk metric. However, it's important to keep in mind that DESC's results
 20 are flawed due to unreasonable assumptions and a continued failure to model candidate plans with
 21 near-term clean energy, and those results must be corrected.

22 **Q. DID DESC CHANGE ITS PLAN SELECTION APPROACH?**

1 A. No. Mr. Bell states that "...RP2 is the preferred plan because from the customer
2 affordability and least cost standpoint it is the plan that is most beneficial to customers under
3 current conditions."⁶⁶ In other words, RP2 has the lowest forecasted cost under the base case
4 scenario, therefore DESC selected RP2 as its preferred plan.

5 **RESPONSES RELATED TO FUTURE IRPS**

6 **Q. WHAT ADDITIONAL RECOMMENDATIONS DID YOU MAKE IN YOUR**
7 **DIRECT TESTIMONY FOR FUTURE IRPS?**

8 A. In my direct testimony, I made several additional recommendations for future IRPs that
9 have not been addressed yet in this surrebuttal testimony. Those recommendations relate to the
10 following topics:

- 11 1. Capacity expansion modeling
- 12 2. Coal retirements
- 13 3. DSM as a resource option
- 14 4. Natural gas and CO2 price assumptions
- 15 5. Modeling load forecast sensitivities
- 16 6. Exploration of risk assessment approaches
- 17 7. Integration study

18 **Q. HOW DO YOU RESPOND TO DESC'S REBUTTAL TESTIMONY ON**
19 **CAPACITY EXPANSION MODELING?**

20 A. Witness Bell states that "DESC is beginning the process of implementing a least cost
21 optimization model to use in future IRPs" and identifies that model as "PLEXOS LT – Capacity
22 Expansion module."⁶⁷ I support DESC's decision to implement a capacity expansion model.

⁶⁶ DESC Witness Bell rebuttal testimony at 33.

⁶⁷ DESC Witness Bell rebuttal testimony at 25-26.

1 However, the Commission should understand that capacity expansion models are complex, and
2 that there are a variety of software options available that offer a variety of features and
3 functionality. The choice of software is an important one. It hinges on the capabilities needed to
4 ensure the model is providing valuable information to the IRP process, given South Carolina policy
5 and regulatory directives and the particular circumstances of DESC's system. While I support
6 implementing capacity expansion modeling within DESC's IRP process as soon as possible, due
7 diligence is necessary in identifying the best software to use. Additionally, there are multiple ways
8 in which a capacity expansion model can be used within the overall IRP development, and
9 Commission guidance on the most valuable approaches for using such software would greatly
10 benefit the planning process.

11 Therefore, I reiterate my direct testimony recommendation that the Commission should
12 solicit parties' recommendations on guidelines for incorporating this modeling tool into the 2021
13 IRP and approve a set of guidelines prior to DESC's 2021 IRP development process. Such a
14 solicitation could include a directive that DESC consider multiple potential capacity expansion
15 models, including review and comment on those models by interested parties. It could also cover
16 approaches to utilizing the software in development of the IRP.

17 **Q. HOW DO YOU RESPOND TO DESC'S REBUTTAL TESTIMONY ON COAL**
18 **RETIREMENTS?**

19 A. Witness Bell notes that "DESC plans to conduct detailed retirement studies for potential
20 retirement candidates in the coming years" but asserts that such studies are "time consuming,
21 resource intensive and expensive,"⁶⁸ and that the Company may be able to include them in the
22 2022 IRP update.

⁶⁸ DESC Witness Bell rebuttal testimony at 21.

1 Witness Bell also addresses DESC's choice to not model pre-2028 coal retirements by
2 explaining that "Our experience is that without a significant change in regulation and/or a need to
3 spend significant capital, our customers benefit from continuing to operate the generators that they
4 are paying for and will continue to pay for after retirement." This is another example of DESC
5 pre-judging the outcomes of an economic analysis, and not actually doing the analysis to verify
6 that the results support the Company's expectations. Because the Company didn't model pre-2028
7 coal retirements, we have no knowledge of whether customers would benefit from retiring those
8 assets.

9 The current lack of modeling results related to accelerated coal retirements creates an
10 urgency to explore this topic.⁶⁹ The Commission should recognize that the IRP analysis itself is
11 the most comprehensive means of assessing coal retirement economics, such that evaluating
12 candidate resource plans featuring a range of coal retirement options is a key element of studying
13 potential coal retirements. Additional investigation may be needed to identify what system impacts
14 (for example, transmission network effects and operating reserves impacts) must be represented,
15 and appropriate assumptions to adopt for those impacts when modeling coal retirements in an IRP.
16 However, there is no barrier to evaluating accelerated coal retirements within candidate resource
17 plans today, using the best information currently available. Additionally, preliminary economic
18 analyses could help to prioritize particular generating units, combinations, and/or timelines for
19 more detailed IRP modeling.

20 Given the importance of accurately assessing the potential for coal retirements, and
21 DESC's lack of urgency on the topic despite agreeing to explore it further, I therefore reiterate my
22 direct testimony recommendation that DESC should be required to perform a comprehensive coal

⁶⁹ See discussion of coal retirements in Sercy direct testimony at 13 and 15.

1 retirement analysis to inform development of its 2021 IRP, and the Commission should solicit
2 parties' recommendations on guidelines for performing this analysis and approve a set of
3 guidelines prior to DESC's 2021 IRP development process. Such an investigation could identify
4 what information is needed along with reasonable timelines for providing it, and how detailed coal
5 retirement studies would then be used within future IRP analyses that could ultimately demonstrate
6 that the most reasonable and prudent plan features a particular schedule of coal unit retirements.

7 **Q. DID DESC RESPOND TO YOUR DIRECT TESTIMONY ON DSM AS A**
8 **RESOURCE OPTION?**

9 A. Not directly. My testimony stated that DESC did not include DSM as a resource option
10 available to add to candidate resource plans, and the Company also did not evaluate different levels
11 of DSM across all gas-CO2 scenarios. As a consequence, the IRP does not comply with Act 62
12 and does not align with industry best practices for modeling DSM within IRPs.⁷⁰

13 As part of its supplemental analysis and rebuttal testimony, DESC did produce cost results
14 for its High DSM and Low DSM cases across all six gas-CO2 scenarios, which provides a more
15 complete picture of the impacts of varying DSM levels. I have not reviewed the details of DESC's
16 DSM modeling, in terms of assumptions for program costs and energy savings. Additionally, given
17 that DESC did not consider DSM a resource option that could be integrated into its candidate plans
18 on an equal footing with supply-side resources, it's possible that the candidate plans are not
19 designed in an optimal way in relation to the DSM components of the plans. And given the
20 unreasonable assumptions I have discussed for natural gas prices and other inputs, again DESC's
21 cost results are unreliable.

⁷⁰ Sercy direct testimony at 19-20.

1 However, taking the results at face value, they do yield some basic insights into DSM
 2 impacts. Exhibit 2 Table 2 shows that the least cost plan in each of the six gas-CO2 scenarios is a
 3 plan that includes the highest level of DSM modeled by DESC, and generally many of the higher
 4 ranking plans for any given scenario include High DSM. Further, Exhibit 2 Tables 3 and 4 show
 5 a clear trend of plans with High DSM attaining high rankings for the two risk metrics I've
 6 proposed, cost range and max regret. This includes the top ranked plans for both risk metrics. And
 7 in fact, for any given plan, more DSM translates to a lower cost range and a lower max regret – in
 8 other words, moving from Low DSM to Medium DSM to High DSM progressively reduces the
 9 risk of any given candidate plan. That effect is intuitive given that DSM displaces fossil generation.
 10 Notably, this risk-reducing benefit of DSM is not typically measured or included at all within DSM
 11 potential studies that use the standard DSM cost-effectiveness tests to screen measures and
 12 programs, because those tests don't consider the uncertainty inherent in fuel price forecasts or in
 13 policy outcomes such as greenhouse gas regulations.

14 While the issues I've described above make DESC's results largely unreliable, the strength
 15 of DSM on a relative basis within the results is noteworthy, as are the risk-reducing benefits of
 16 this resource option.

17 **Q. HOW DO YOU RESPOND TO DESC'S REBUTTAL TESTIMONY ON NATURAL**
 18 **GAS AND CO2 PRICES IN FUTURE IRPS?**

19 A. DESC Witness Bell explains that "the Company intends to work with ORS and other
 20 interested parties" to "Reexamine its natural gas forecasts" and "Include additional CO₂ price
 21 sensitivities in future IRP scenarios based on appropriate forecasts."⁷¹

⁷¹ DESC Witness Bell rebuttal testimony at 18-19.

1 The Commission is receiving a substantial volume of testimony on natural gas price
2 forecasts and CO2 pricing assumptions, and must consider what constitutes a reasonable set of gas
3 and CO2 prices in this proceeding. Those deliberations and final decisions should be the basis of
4 guidance for future IRPs as well. The Commission could, for example for natural gas prices, direct
5 DESC to use the AEO reference, high, and low gas price projections now and in the future. Or the
6 Commission could adopt the AEO prices in this proceeding but also specify that for future IRPs,
7 gas prices must be derived from a credible supply-demand model comparable to the DOE's model
8 NEMS, and/or that gas prices must include a "wide but plausible" range of forecasts.⁷²

9 **Q. HOW DO YOU RESPOND TO DESC'S REBUTTAL TESTIMONY ON**
10 **MODELING LOAD FORECAST SENSITIVITIES?**

11 A. DESC Witness Bell includes "Expand the number of sensitivities the IRP analyzes to
12 include both DSM scenarios and a range of load growth sensitivity factors as appropriate"⁷³ in the
13 list of issues on which DESC "intends to work with ORS and other interested parties" for future
14 IRPs. Additionally, DESC Witness Lynch specifies that the Company will consider providing a
15 wider range of load forecasts in the future, and explains that DESC did not actually model load
16 forecasts in the 2020 IRP economic analysis, other than the base forecast, because the Company
17 believed it would "produce too many scenarios making it unreasonably difficult to draw
18 meaningful conclusions from the study."⁷⁴

19 My direct testimony provides support for including a wider range of load forecasts, based
20 on the CRA Report's findings that DESC's narrow load sensitivities are out of step with regional
21 peer utilities, and for modeling those load sensitivities within the economic analysis, in order to

⁷² Sercy direct testimony at 26-31.

⁷³ DESC Witness Bell rebuttal testimony at 18.

⁷⁴ DESC Witness Lynch rebuttal testimony at 10.

1 ascertain the performance of candidate plans under different load conditions that may arise.⁷⁵
2 There is no barrier to designing the overall IRP analysis well, such that a range of load forecasts
3 can be modeled along with a range of other uncertain factors like natural gas prices, and without
4 producing an unmanageable volume of results. Use of a capacity expansion model can aid in
5 achieving such an objective, and design of internally consistent scenarios based on plausible future
6 pathways⁷⁶ is another approach that can ensure an appropriate range of uncertainties is explored
7 while keeping scenario counts modest.

8 The Commission is receiving testimony on this topic in this proceeding, and can and should
9 set reasonable expectations for future IRPs as part of its order.

10 **Q. DID DESC RESPOND TO YOUR DIRECT TESTIMONY RECOMMENDATION**
11 **THAT THE PSC INITIATE AN EXPLORATION OF RISK ASSESSMENT**
12 **APPROACHES?**

13 A. No, the Company did not respond to that recommendation. Given DESC's lack of
14 engagement on this topic and failure to include appropriate measures of risk within its IRP, it's
15 clear that a review of risk assessment approaches would provide great value and guide the
16 Commission's and DESC's future compliance with Act 62.

17 **Q. DID DESC RESPOND TO YOUR DIRECT TESTIMONY RECOMMENDATION**
18 **THAT THE PSC INITIATE THE INTEGRATION STUDY AUTHORIZED BY ACT 62,**
19 **INCLUDING A PARTICULAR COMPLETION TIMELINE AND TOPICS THAT**
20 **SHOULD BE COVERED?**

⁷⁵ Sercy direct testimony at 25-26.

⁷⁶ For example, a High Economic Growth scenario, an Economic Downturn Scenario, a Low Carbon Policy scenario, each of which has its own internally consistent set of load, gas price, CO2 price, and other assumptions, rather than modeling every possible combination of each sensitivity factor. The TVA 2019 IRP is an example where this approach to scenario design is utilized. TVA 2019 IRP at 6-1 to 6-3.

1 A. No.

2 **Q. HOW DO YOU RESPOND TO DESC WITNESS BELL'S REBUTTAL**
 3 **TESTIMONY CHARACTERIZING YOUR COMMENTS ON CRA AS UNFAIR?**

4 A. My direct testimony stated my view that some of CRA's work product was well-supported
 5 and well-reasoned, and some was not, and in my testimony I detailed many instances in which
 6 CRA's conclusions and recommendations were not reasonable. Those instances, along with others
 7 not covered in my testimony, are part of what the Commission is considering in this case.

8 I also pointed out that CRA was not selected and paid by the Commission, unlike Power
 9 Advisory in the 2019 avoided cost dockets. Rather, CRA was paid by DESC -- a fact that the
 10 Commission must consider in assessing the credibility and weight of CRA's conclusions. Mr.
 11 Bell's rebuttal testimony does not dispute this point.

12 **RESPONSES ADDRESSING PROCUREMENT**

13 **Q. HOW DO YOU RESPOND TO ORS WITNESS HAYET'S TESTIMONY ON**
 14 **TRANSMISSION SYSTEM PLANNING AND INVESTMENT?**

15 A. Mr. Hayet states that DESC's IRP "noted that the addition of intermittent resources, namely
 16 new solar resources, will require additional study to determine the impacts on the existing
 17 transmission system." Mr. Hayet continues by stating "The additional investment may be
 18 significant, and the physical assets will need to be in operation to add significant new solar
 19 resources, if that ultimately becomes part of the Company's resource plan."⁷⁷

20 The SCSBA supports maintaining a robust transmission network that is reliable and
 21 enables the full range of resources to compete for a role in South Carolina's electricity mix,
 22 including performing grid studies that identify network needs and opportunities. The

⁷⁷ ORS Witness Hayet direct testimony at 13-14.

1 Commission's prior decisions on grid interconnection provide a strong foundation for maintaining
2 the state's transmission and distribution networks. In Order 2016-191, the Commission established
3 a statewide generation interconnection procedure that governs both transmission- and distribution-
4 level interconnections. Broadly, these procedures require that resources seeking to interconnect to
5 South Carolina grids must complete an interconnection study process before they are permitted to
6 interconnect. That process includes comprehensive, project-specific assessments of grid impacts,
7 and if the grid is negatively impacted, the project must pay for grid upgrades to alleviate those
8 impacts in order to interconnect. These costs are not borne by ratepayers.

9 Thus, under existing Commission procedures, there is already a well-tested system in place
10 wherein the appropriate grid studies are completed before projects interconnect. I point this out to
11 emphasize that it would be unreasonable to conclude that additional solar PV cannot be added to
12 the DESC system until DESC completes some number of as-yet undefined grid studies.

13 **Q. YOU MENTIONED THAT INTERCONNECTING PROJECTS MUST PAY FOR**
14 **THEIR OWN GRID UPGRADES. COULD YOU PROVIDE ADDITIONAL DETAIL ON**
15 **HOW THIS RELATES TO THE 2020 IRP?**

16 A. Yes. If the 2020 IRP were to identify solar PPAs as part of the most reasonable and prudent
17 resource plan, then those PPAs would need to be procured. One straightforward option for
18 procuring those resources would be a competitive solicitation process akin to North Carolina's
19 Competitive Procurement of Renewable Energy ("CPRE") program. Under such a process, DESC
20 would issue a Request for Proposals for the capacity to be procured. Individual projects would
21 submit bids and compete to fulfill the request. Some prospective projects may be sited in areas that
22 require grid upgrades, in which case the cost of the upgrades could be incorporated into the project
23 bid. The competition to provide the limited amount of solar PPA volume would then identify the

1 projects that are most cost-effective overall, including interconnection and all other costs. In such
2 a procurement process, any projects that cannot compete due to high interconnection costs would
3 ultimately not be selected. Further, the solar PPA costs modeled in the 2020 IRP could be
4 considered by the Commission in designing the competitive procurement program, to ensure that
5 the cost of the procured solar PPAs is reasonably comparable to the assumed costs within the IRP,
6 including actual interconnection costs.

7 **Q. COULD YOU COMMENT FURTHER ON HOW THE 2020 IRP MODELING**
8 **COULD BE USED TO HELP DESIGN A COMPETITIVE PROCUREMENT PROCESS?**

9 A. Yes. This topic relates to the point I made above about the solar PV supply curve in DESC's
10 territory. That is, I expect that some projects can be developed at the generic 38.94 \$ / MWh cost
11 assumption for 2023 discussed above, whereas some projects may be developed at an even lower
12 20-year PPA price point because of economies of scale, below-average interconnection costs,
13 and/or other cost advantages. A set of PPA price sensitivities⁷⁸ would provide the Commission
14 valuable information related to the supply curve in DESC's territory. To ensure that ratepayer
15 interests will continue to be protected, that cost information could be used to inform the design
16 parameters for a competitive procurement program. For example, the procurement could seek up
17 to 400 MW of solar PPAs, with constraints on bid selection to ensure that the aggregate cost of the
18 procurement does not unreasonably exceed the range of assumed costs in the 2020 IRP.

⁷⁸ By price sensitivities I mean executing several modeling runs that are identical other than changing one variable: the assumed 2023 PPA price. Importantly, such a sensitivity would be categorically different from the uncertainty analysis reflected in the natural gas and CO2 scenarios modeled in the 2020 IRP, due to the fact that DESC would only procure solar PPAs at a fixed cost, known in advance, and previously determined to be economic for customers. In contrast, future natural gas and CO2 prices are uncertain, and DESC customers are already exposed to those risks due to the large shares of fossil generation on DESC's system today.

Price sensitivities would provide further value in that they may identify a solar PPA cost threshold for cost-competitiveness with the Company's preferred plan, RP2. This could reveal, for instance, that solar PPAs are not part of the most reasonable and prudent plan at a price point of 38.94 \$ / MWh, but that solar PPAs would be part of the most reasonable and prudent plan as determined by the Commission at a 34 \$ / MWh price point. Thus, a PPA price sensitivity analysis would at least partially capture the supply curve nature of the solar PV market, thereby contributing to giving solar PV a fair chance to compete within candidate resource plans and simultaneously providing information that could guide competitive procurement design. Given that considerable value, I am refining my original modeling recommendations to include such a sensitivity analysis. I recommend that solar PPAs be modeled at the generic 38.94 \$ / MWh price point, as well as 36 \$ / MWh and 34 \$ / MWh.

Q. WHAT OTHER STATEMENTS ARE MADE IN THE ORS REPORT RELATING TO SOLAR PV ASSUMPTIONS, AND HOW DO YOU RESPOND?

A. In reviewing the resource plan cost results, the ORS Report states that RP7 and RP8 "assume there will be no reliability issues associated with adding intermittent renewable resources, which is unlikely without modifications to the transmission system and changes to the operation of its generating resources, including maintaining higher operating reserves."⁷⁹ Additionally, in discussing the seven factors that Act 62 directs the Commission to consider, the ORS Report suggests that there is a trade-off embedded in the option of mitigating commodity price risk via renewable resources: "Commodity price risks that impact gas-fired resources are mitigated in the RPs that reflect more renewable resources, however, the reduction in commodity price risk must be balanced against concerns about customer affordability, integration, and reliability impacts

⁷⁹ ORS Report at 65.

1 associated with those types of resource additions.”⁸⁰ A similar suggestion is made relating to
2 diversity of generation supply.

3 The ORS Report does not review DESC’s modeling assumptions for system operating
4 reserves as they relate to renewable energy, and does not acknowledge that the Company’s
5 production simulations already assume a large commitment of operating reserves for each MW of
6 solar added within the candidate resource plans. My direct testimony discusses how these
7 operating reserves assumptions are excessive and conflict with previous Commission decisions.⁸¹
8 In other words, rather than unreasonably overlooking renewables integration and reliability
9 impacts, DESC has actually over-represented these parameters in its modeling. I discuss
10 modifications to the transmission system to accommodate renewables above. In summary, there
11 are no integration, reliability, or grid-related issues with renewable resources that are not already
12 accounted for in DESC’s modeling and existing Commission interconnection procedures. In fact,
13 DESC’s cost results have inappropriately inflated the costs of renewable resources through
14 excessive operating reserves requirements – an issue that should be corrected to ensure that the
15 costs of candidate resource plans that include renewables are realistically represented.

16 **Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON SOLAR INTEGRATION**
17 **COST ASSUMPTIONS?**

18 A. Yes. My direct testimony recommends that the Commission-adopted 0.96 \$ / MWh
19 integration cost assumption for solar PV be applied to the resource plan modeling in the 2020 IRP,
20 in place of the Company’s approach to representing solar PV operating reserves. For clarity, the
21 Commission’s Orders in DESC’s Avoided Cost docket adopted this integration cost figure as an
22 interim value for use until a more rigorous integration study is completed and approved by the

⁸⁰ ORS Report at 19.

⁸¹ Sercy direct testimony at 44-45.

Commission.⁸² Any future actions taken based on the outcome of the 2020 IRP proceeding could consider the results of that integration study, once it is completed and approved.

For example, if the Commission identified the most reasonable and prudent plan to include solar PPAs with CODs in 2023, any updated integration cost value(s) could be factored into PPA pricing (and therefore any pricing constraints) in a competitive procurement process.

Q. BEFORE YOU COMPILE AN UPDATED LIST OF YOUR RECOMMENDATIONS, COULD YOU PROVIDE A HIGH-LEVEL SUMMARY OF THE ADDITIONAL ANALYSIS YOU ARE PROPOSING, AND THE RATIONALE FOR PERFORMING THAT ANALYSIS?

A. Yes. Given the deficiencies in DESC's original and supplemental analyses, which I've detailed in my direct and surrebuttal testimony, the results that the Company has produced so far are not reliable for purposes of selecting the most reasonable and prudent plan under the Act 62 requirements. I'm proposing limited additional analysis so that the Commission has a valid set of cost results from which to balance the Act 62 factors and identify the most reasonable and prudent plan. Ideally, a broader analysis would be performed, but due to the late stage in the proceeding, I am limiting my recommended additional analysis to include three candidate resource plans: RP2, which the Company has consistently favored, and two revised versions of RP7, which I've named RP7-A and RP7-B. These two revised candidate plans ensure that at least two of the many possibilities for adding clean energy PPAs to the DESC system in the near term are actually being evaluated within the IRP. I'm proposing that these three candidate plans be modeled, with several unreasonable inputs revised to use reasonable assumptions. Among those inputs are revised base, low, and high gas prices, and a revised CO2 price, plus several others. The three candidate plans

⁸² SCPSC Order 2020-244 at 5-6.

1 each include the Medium DSM portfolio. Finally, I'm recommending that a sensitivity analysis be
2 performed for solar PPA prices.

3 My proposal thus requires three candidate resource plans to be modeled across six gas-
4 CO2 scenarios, and with three solar PPA price sensitivities, for a total of 42 new cost results to be
5 produced.⁸³ Given the 144 cost results the Company produced between July 10 and August 28,
6 there is no practical constraint on producing 42 additional results in a timely fashion. These 42
7 results would then be the basis for the Commission's decision as to the most reasonable and
8 prudent plan to select and implement at this time.

9 **Q. WHY ARE YOU RECOMMENDING THAT COST RESULTS FOR RP7-A AND**
10 **RP7-B BE COMPARED TO THE REVISED COST RESULTS FOR RP2?**

11 A. DESC has maintained that RP2 is its preferred plan. A limited additional analysis, that
12 could be performed in a timely fashion and that compares RP7-A, RP7-B, and RP2, would
13 determine which of these three plans is the most reasonable and prudent plan under Act 62.

14 If the Commission identifies other candidate plans that should be included in an additional
15 analysis, I recommend ensuring that versions of those other plans are also modeled that add solar
16 and solar plus storage in 2023, so that the analysis is able to isolate the impact of taking those near-
17 term actions. For example, if RP1 was included in the analysis, I would recommend also including
18 a version of RP1 that adds 400 MW of solar PPAs in 2023, and another version that adds 400 MW
19 of solar PPAs and 100 MW of storage PPAs in 2023. Doing so would ensure that if RP1 is found
20 to be more reasonable and prudent than RP2, then RP1 is also being compared to plans that are
21 identical except for clean energy additions in 2023, thus giving these clean energy additions a fair

⁸³ For clarity, RP2 would be modeled across each of the six gas-CO2 scenarios, producing six cost results. RP7-A would be modeled across each of the six gas-CO2 scenarios, and with each of three solar PPA price assumptions, producing 18 cost results. And RP7-B would be modeled across each of the six gas-CO2 scenarios, and with each of three solar PPA price assumptions, producing 18 cost results.

1 chance to compete as part of any candidate plans undergoing additional evaluation. If a resource
 2 plan is selected that includes procurement of solar and/or storage resources, the Commission
 3 should direct DESC to initiate a procurement of those resources, so that any procurement can be
 4 completed in time to accommodate the commercial operation dates set forth in the selected
 5 resource plan.

6 UPDATED RECOMMENDATIONS

7 **Q. PLEASE PROVIDE THE UPDATED COMPILATION OF YOUR**
 8 **RECOMMENDATIONS FOR THE 2020 IRP.**

9 I recommend that the Commission require DESC to:

- 10 1. Revise RP7 into two new candidate resource plans, as detailed below;
- 11 2. Correct the flexible solar PPA cost assumptions to the DESC ATB low case,
 12 adjusted to safe harbor the 22% ITC for four years and recognize Southeastern
 13 regional installed costs, which overall yields 20-year solar PPA pricing at 38.94 \$
 14 / MWh for 2023 and 34.93 \$ / MWh for 2043;
- 15 3. Correct the incremental flexible solar PPA capacity value assumptions to the
 16 appropriate current ELCC;
- 17 4. For battery storage PPA cost assumptions, use the capital and fixed O&M costs
 18 from the ATB low case, adjusted to safe harbor the 22% ITC for four years, which
 19 overall yields 15-year battery PPA pricing at 129.79 \$ / kW-year for 2023 and 95.28
 20 \$ / kW-year for 2038, with no battery performance degradation during the 15-year
 21 PPA period;

- 1 5. Correct the system flexibility requirements to the \$0.96 per MWh recognized solar
2 integration cost while eliminating the solar-specific operating reserve and spinning
3 reserve requirements;
- 4 6. Use the AEO low, reference, and high gas prices I have described in place of
5 DESC's low, base, and high gas prices, and use the AEO high CO2 case in place
6 of DESC's \$25 CO2 case, in the revised cost analysis;
- 7 7. Re-model the costs of RP2 as well as the revised RP7 plans, for comparison
8 purposes;
- 9 8. For the revised RP7 plans, model each of three solar PPA price sensitivities (38.94
10 \$/ MWh, 36 \$ / MWh and 34 \$ / MWh);
- 11 9. Re-calculate the total 40-year levelized NPV revenue requirements results for RP2
12 and the revised RP7 plans;
- 13 10. Not make additional discretionary changes to the plans or calculations; and
- 14 11. File the cost modeling results with the PSC, including the 40-year levelized NPV
15 revenue requirements for each of the three candidate resource plans identified in
16 these recommendations, across each of the six gas-CO2 scenarios identified in these
17 recommendations, and for the revised RP7 plans with each of the three solar PPA
18 price assumptions, and including the cost range and minimax regret scores and
19 rankings as presented in my testimony. For cost results presentation and for
20 calculating the risk metrics, the results should be arranged as a seven by six matrix,
21 where RP2 and the three solar price sensitivities each for RP7-A and RP7-B make
22 up seven total versions of the three candidate plans, and these seven versions are

1 each modeled across the six gas-CO2 scenarios. This will yield 42 total cost results,
2 seven cost ranges, and seven max regret scores.

3 The new calculations and results should be reviewed by the ORS, including a verification
4 that DESC adjusted the expansion plans and calculations as directed and did not make any
5 inappropriate additional changes. These new results would then serve as the basis for the
6 Commission's consideration and balancing of the seven Act 62 factors, and selection of the most
7 reasonable and prudent of the three candidate resource plans covered in the final analysis.

8 I recommend that the Commission reject DESC's approach of selecting the preferred plan
9 based on a standard of least cost in a "base" or "most likely" scenario, and affirm the approach of
10 selecting the preferred plan based on a balancing of the Act 62 factors, including a systematic,
11 quantitative assessment of commodity price risk and diversity of generation supply.

12 **Q. PLEASE PROVIDE THE REVISED RP7 PLANS TO BE RE-MODELED.**

13 A. RP7-A should modify the original RP7 expansion plan by adding the 400 MW of flexible
14 solar PPAs in 2023 instead of 2026, and by eliminating the battery storage addition entirely. The
15 conventional CT additions to maintain the 14% base reserve margin and short-term power
16 purchases to maintain the 21% peaking reserve margin should be adjusted appropriately to meet
17 the reserve margin target at least cost.

18 RP7-B should modify the original RP7 expansion plan by adding the 400 MW of flexible
19 solar PPAs in 2023 instead of 2026, and by adding the 100 MW battery storage in 2023 instead of
20 2026. The battery storage addition should be modeled as battery storage PPAs that are paired with
21 solar PV and are thus able to utilize the federal ITC. The conventional CT additions to maintain
22 the 14% base reserve margin and short-term power purchases to maintain the 21% peaking reserve
23 margin should be adjusted appropriately to meet the reserve margin target at least cost.

1 **Q. PLEASE PROVIDE THE UPDATED COMPILATION OF YOUR**
2 **RECOMMENDATIONS FOR FUTURE IRPS.**

3 A. I recommend that the Commission enter an Order directing DESC to meet the following
4 requirements in formulating its 2021 and later IRPs and IRP updates.:

- 5 1. DESC should be required to use capacity expansion modeling in developing its
6 2021 IRP, and the Commission should solicit parties' recommendations on
7 guidelines for incorporating this modeling tool into the 2021 IRP and approve a set
8 of guidelines prior to DESC's 2021 IRP development process;
- 9 2. DESC should be required to perform a comprehensive coal retirement analysis to
10 inform development of its 2021 IRP, and the Commission should solicit parties'
11 recommendations on guidelines for performing this analysis and approve a set of
12 guidelines prior to DESC's 2021 IRP development process;
- 13 3. For its 2021 IRP, DESC should be required to include DSM and purchased power
14 as resource options that are incorporated into candidate resource plans and
15 evaluated across multiple scenarios;
- 16 4. For its 2021 IRP, DESC should be required to build candidate resource plans to
17 meet its full peaking reserve margin target, and the resource plan analysis should
18 determine what type of resources best meet the peaking increment;
- 19 5. For the 2021 IRP, DESC should be required to develop a wide but plausible range
20 of load forecasts, and ensure that cost modeling captures each resource plan's
21 capabilities to adapt to load that diverges from the base forecast;

- 1 6. For the 2021 IRP, DESC should be required to use a wide but plausible range of
2 gas price projections from AEO or another public, credible fundamental gas supply-
3 demand model;
- 4 7. For the 2021 IRP, DESC should be required to use wide but plausible
5 zero/medium/high CO2 cost projections from AEO or other public sources;
- 6 8. The Commission should initiate an exploration of approaches to risk assessment
7 and management within IRP that can best satisfy Act 62 requirements, to include
8 consideration of various risk metrics, risk modeling tools, and risk management
9 strategies;
- 10 9. The Commission should initiate the integration study authorized by Act 62, with a
11 goal of completing the study in time for its findings and recommendations to be
12 incorporated into DESC's 2021 avoided cost proposal. The integration study
13 should cover the following topics:
 - 14 a. Effect of various renewable penetration levels, from current levels to very
15 high;
 - 16 b. Impact of various renewable energy operating modes;
 - 17 c. Impact of expanded balancing areas (such as an EIM platform or other
18 means of joint system operation), sub-hourly scheduling and dispatch, and
19 improved renewable energy forecasting;
 - 20 d. Impact of industrial and commercial demand response;
 - 21 e. Impact of battery storage;
 - 22 f. Impact of pumped hydro storage;

- 1 g. Recommended methods for decomposing and identifying system ancillary
2 services needs;
- 3 h. Recommended metrics for system flexibility;
- 4 i. A comprehensive review of options for enhancing system flexibility, with
5 generic cost estimates for each;
- 6 j. Discussion of the system flexibility needs and capabilities of conventional
7 generation, including but not limited to impacts of coal retirement;
- 8 k. Recommendations for incorporating system flexibility into IRP; and
- 9 l. Recommendations for capturing system flexibility value within avoided
10 cost tariffs.

11 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

12 **A. Yes.**

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